BACT Analysis – CO Emissions at IPP

Best Available Control Technology (BACT).

IGS was constructed under a PSD permit which required BACT. Since the proposed CO emissions increases may trigger a major PSD modification, a Top Down CO BACT analysis was performed.

Top-Down BACT Process

EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps are:
Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

Each of these steps has been conducted for CO and is described below.

Potential control technologies for CO were identified from a number of sources including the EPA RBLC database, control technology vendors, technical journals and web sites, and other recently issued permits

CO Analysis

The BACT analysis for CO is presented below.

Step 1 – Identify All Control Technologies

Only two control technologies have been identified for control of CO on coal-fired boilers:
Catalytic oxidation
Combustion controls
Catalytic oxidation is a post-combustion control device that would be applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

Step 2 – Eliminate Technically Infeasible Options

Catalytic oxidation has been the control alternative used to obtain the most stringent control level for CO emitting from primarily combustion turbines firing natural gas. This alternative, however, has never been applied to a PC-fired unit so this technology has not been demonstrated in practice in this application.

For sulfur containing fuels, such as coal, an oxidation catalyst will convert SO_2 to SO_3 and therefore this conversion would result in unacceptable levels of corrosion to the flue gas system. Generally, oxidation catalysts are designed for a maximum particulate loading of 50 milligrams per cubic meter (mg/m^3). The existing IPP boilers will have a particulate loading upstream of the fabric filter in well above this value. In addition, trace elements present in coal, in particular chlorine, are poisonous to oxidation catalysts. There are no catalysts developed that have or can be applied to PC-fired boilers due to the high levels of PM and trace elements present in the flue gas.

Although the catalyst could be installed downstream of the fabric filter where the concentration of PM in the flue gas is much lower than at the outlet of the boiler, the flue gas temperature at that point will be approximately 300°F. This is well below the minimum temperature required (600°F) for operation of oxidation catalyst. The flue gas would have to be reheated, resulting in significant unfavorable energy and economic impacts.

Other technologies were also reviewed, but eliminated from consideration for this application. Please refer to Table 1.

For these reasons, as well as the generally low levels of CO in PC-fired units, no PC-fired boilers have been equipped with oxidation catalysts. Use of an oxidation catalyst system in the PC-fired boiler is thus considered technically infeasible. Thus, this alternative cannot be considered to represent BACT for control of CO.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, combustion control is the only remaining technology for this application.

Step 4 – Evaluate Most Effective Controls and Document Results

There are no environmental or energy costs associated with combustion control.

Step 5 – Select BACT

Based on the above analysis, a Good Combustion Practice (GCP) for CO is selected as BACT. IPSC has provided a detailed discussion on what GCP entails for boiler operation utilizing OFA.

With regard to CO, BACT can only be provided through the application of good combustion practices (GCP), which is already in place, and is intimately related to best boiler performance, a strong business incentive. No other technological controls are available for CO in coal-fired boilers.

Recent CO Permitting:
Table 2 represents recent permitting action for CO. Accordingly, IPSC recommends that for OFA permitting, a limit equivalent to 0.143 lb/mmbtu in pounds per hour based upon a 30 day rolling average would be protective of the environment and meet best available control technology (BACT). At design heat input, 0.143 lb/mmbtu represent 180 ppm CO concentration. When converted, this equals 1320 lb/hr at 2.25% O_2. When related back to percent O_2 levels in the boiler, historical operation indicates that this is the average result when OFA is operated in the GCP range shown on the test result curves. Coal combustion naturally incurs fluctuations in emissions due to varying coal quality and boiler operating conditions. We believe that GCP contains those fluctuations, and therefore recommend that a single permit limit of 1320 lb/hr based upon a 30-day rolling average (except for start-up, shut down, planned / maintenance outage, or malfunction) represents BACT for this type of retro-fit control device.

TABLE 1 – Other CO Control Technologies

Technology	Brief Description	Applicability to Coal-Fired Boiler
Regenerative Thermal Oxidation	Destroys CO by passing gas stream through a flame or high temperature region. A Regenerative Oxidizer is also a Direct Fired oxidizer that employs integral primary heat recovery. However, the RTO operates in a periodic, repetitive cycle rather than a continuous mode. Instead of conventional heat exchangers which indirectly transfer heat from the hot side to the cold side across exchanger walls, RTOs use a store and release mechanism. The nature of an RTO heat recovery process requires it to have at least two beds of appropriate heat recovery media.	Not intended for, nor applicable to, Coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler. If a flame type oxidizer is used, the CO exiting the unit may be higher than the low levels of CO in a power plant flue gas.
Recuperative Thermal Oxidation	Destroys CO by passing gas stream through a flame or high temperature region. A recuperative oxidizer consists of a combustion chamber, a burner, and a heat exchanger/shell that pre-heats the incoming air.	Not intended for, nor applicable to, Coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler.
Flares	A flare is a direct combustion device in which air and all combustible gases react at the burner with the objective of complete and instantaneous oxidation of the combustible gases. Flares are used either continuously or intermittently and are not equipped with devices for fuel-air mix control or for temperature control.	Not intended for, nor applicable to, Coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler. If a flame type oxidizer is used, the CO exiting the unit will be higher than the low levels of CO in a power plant flue gas.
Afterburners	The simplest Thermal Oxidizer is a Direct Fired unit (sometimes referred to as an After-Burner) that employs no heat recovery. In this system, a fuel burner (mostly natural gas fired) raises the temperature of the pollutant laden air to a predetermined combustion temperature. In order to achieve a high level of hydrocarbon destruction, the heated air is kept at the combustion chamber setpoint for a predetermined minimum residence (or dwell time).	Not intended for, nor applicable to, Coal-fired power plants. This technique is only applicable to gas streams with high levels of CO, and not the low CO concentrations exiting a well operated boiler. If a flame type oxidizer is used, the CO exiting the unit may be higher than the low levels of CO in a power plant flue gas.

Table 2 - Recently Issued PSD Permits - CO Limits

Name	Type/Size	CO Limit	Comments
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.16 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.15 lb/ mmbtu (30 day rolling average)	Combustion control CEMS used for compliance
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance If CO and NOx limit cannot be met simultaneously, State will revise CO limit
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.10 lb/mmbtu (30 day rolling avg)	Combustion control CEMS used for compliance
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Plum Point Energy Station Unit 1 Arkansas	Pulverized Coal 550 – 800 MW	0.16 lb/mmbtu	Combustion control CEMS used for compliance
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Council Bluffs Energy Center Unit 4 Iowa	Pulverized Coal 750 MW	0.154 lb/mmbtu (1 day avg) 5,177 tpy	Combustion control CEMS used for compliance If CO and NOx limit cannot be met simultaneously, State will revise CO limit

All the permits above, except Bull Mountain Roundup, exempt startup, shutdown and malfunction in the short term (1 hour, 3 hour, 24 hour and 30 day) emission limits.